Dean, Ouisha <ouisha.dean@solvay.com>

Fwd: Permit

1 message

Brown, Tim <tim.brown@solvay.com> Mon, Jan 27, 2014 at 9:33 AM
To: Todd Brichacek <Todd.Brichacek@solvay.com>, Jim Phillip <Jim.Phillip@solvay.com>, David Hansen <david.hansen@solvay.com>, Steven Wojtaszek <Steven.Wojtaszek@solvay.com>, Ryan Schmidt <ryan.schmidt@solvay.com>, Ouisha Toenyes <ouisha.toenyes@solvay.com>, Errol Pitre <errol.pitre@solvay.com>, Patrick Williams <patrick.williams@solvay.com>, Shyla Sims <shyla.allen@solvay.com>, Jim Holley <Jim.Holley@solvay.com>, Kurt Allen <kurt.allen@solvay.com>, Alain Vandendoren <Alain.Vandendoren@solvay.com>
Cc: Tim Martin <tmartin@airsci.com>, Rodger Steen <rgsteen@airsci.com>

All:

Attached from the EPA is the signed permit for the gas boiler project.

Please let me know if there are any questions or concerns.

Tim

---------- Forwarded message ----------
From: **Law, Donald** <Law.Donald@epa.gov>
Date: Mon, Jan 27, 2014 at 9:22 AM
Subject: Permit
To: "Brown, Tim" <tim.brown@solvay.com>

Hot of the scanner.

Hard copies to follow in the mail.

--
Tim Brown
Environmental Services Supervisor
(307) 872-6570
tim.brown@solvay.com

3 attachments

Solvay GHG PSD permit.pdf
440K

Solvay SOB.pdf

SOLVAY2016_1.2_001627

477K

Solvay transmittal letter.pdf
27K

United States Environmental Protection Agency
Region 8
Air Program
1595 Wynkoop Street
Denver, Colorado 80202-1129
January 27, 2014

Air Pollution Control
Prevention of Significant Deterioration (PSD)
Permit to Construct

PSD-WY-000004-2012.001

Permittee:
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant
P. O. Box 1167
Green River, WY 82935

Permitted Facility:
Green River Soda Ash Plant Green River, Wyoming

Table of Contents

Table of Acronyms

BACT	Best Available Control Technology
CEM	Continuous Emission Monitor
CFR	Code of Federal Regulations
CH_4	Methane
CO	Carbon Monoxide
CO_2	Carbon Dioxide
CO_{2e}	Carbon Dioxide Equivalent
EP	Emission Point
FIP	Federal Implementation Plan
FR	Federal Register
GHG	Greenhouse Gas
hr	Hour
lb	Pound
lbpy	Pounds Per Year
MMBtu	Million British Thermal Unit
Mscf	Million Standard Cubic Foot
N_2O	Nitrous Oxide
NSPS	New Source Performance Standards
NO_x	Nitrogen Oxides
PSD	Prevention of Significant Deterioration
PTE	Potential to Emit
QA/QC	Quality Assurance and/or Quality Control
SF_6	Sulfur Hexafluoride
tpy	Tons Per Year
VOC	Volatile Organic Compounds
%	Percent

I. INTRODUCTION

This Federal Prevention of Significant Deterioration (PSD) permit is being issued under authority of 40 CFR 52.21 (PSD) and 52.37 (Federal Implementation Plan (FIP) to issue permits under the PSD requirements to sources that emit greenhouse gases (GHGs). Green River Soda Ash Plant (hereinafter the "Permittee" or "Solvay") proposes to construct a new natural gas fired boiler that will add steam-generating capacity to the Solvay facility. The addition of this natural gas fired boiler with the two existing coal-fueled boilers will allow Solvay the operational flexibility to (1) shut any one of the three boilers down for maintenance without curtailing production, and (2) take advantage of the lower-cost fuel (coal vs. natural gas).

With this project, Solvay expects to increase annual soda ash production by approximately 14 percent. This permit modification assumes no operational limit on combined steam production, and the additional boiler will be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their capacity while the gas boiler would supplement the steam demand.

This additional boiler is a water tube package natural gas fired, 254 MMBtu/hr boiler (Foster Wheeler Model AG 5195) that was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers. In 2003, Solvay purchased the American Soda facility in Garfield County, Colorado, including the Foster Wheeler Model AG 5195 natural gas fired boiler. The boiler will be fueled through the Western Gas Pipeline by a spur currently feeding the Solvay plant.

II. GENERAL PERMIT CONDITIONS

On the basis of findings set forth in Section III, Special Permit Conditions, of this permit, and pursuant to the authority (as delegated by the Administrator) at 40 CFR 52.37, EPA hereby authorizes Solvay to construct the natural gas fired boiler. The authorization is expressly conditioned as follows:

A. PERMIT EFFECTIVE DATE AND EXPIRATION

As provided in 40 CFR 124.15(b), this PSD permit shall become effective 30 days after the service of notice of the permit decision, unless:

1. a later effective date is specified in the decision;

2. review is requested on the permit under 40 CFR 124.19; or

3. no comments requested a change in the draft permit, in which case the permit shall become effective immediately upon issuance.

As no comments were received during the public comment period, this permit shall become effective immediately upon issuance.

As provided in 40 CFR 52.21(r)(2), this PSD permit shall become invalid if construction:

1. is not commenced (as defined in 40 CFR 52.21(b)(9)) within 18 months after the approval takes effect; or

2. is discontinued for a period of 18 months or more; or

3. is not completed within a reasonable time.

Under 40 CFR 52.21(r)(2), EPA may extend the 18 month period upon a satisfactory showing that an extension is justified.

B. PERMIT NOTIFICATION REQUIREMENTS

The Permittee shall notify EPA in writing of:

1. the date construction is commenced, postmarked within 30 days of such date;

2. the actual date of initial startup, postmarked within 15 days of such date. Startup is defined as the setting in operation of an affected facility for any purpose;

3. the date upon which initial performance tests will commence, in accordance with the provisions of Section V., Performance Testing Requirements, of this permit, postmarked not less than 30 days prior to such date; and

4. other events as required elsewhere in this permit.

C. FACILITY OPERATION

At all times, including periods of startup, shutdown, and malfunction, Permittee shall maintain and operate the facility including associated air pollution control equipment in a manner consistent with good air pollution control practice for minimizing GHG emissions. Determination of whether acceptable operating and maintenance procedures are being used will be based on information available to the EPA, which may include, but is not limited to, monitoring results, review of operating maintenance procedures and inspection of the facility.

D. MALFUNCTION REPORTING

1. The Permittee shall notify EPA by mail within 2 working days following the discovery of any failure of air pollution control equipment, process equipment, or of a process to operate in a normal manner, which results in an increase in CO_{2e} emissions above the allowable emission limits stated in Condition III.A. Point Source Emission Limits, of this permit.

2. In addition, the Permittee shall notify EPA in writing within 15 calendar days of any such failure described under Section IV. Recordkeeping Requirements. This notification shall include a description of the malfunctioning equipment or abnormal operation, the date of the initial malfunction, the period of time over which emissions were increased due to the failure, the cause of the failure, the estimated resultant emissions in excess of those allowed in Condition III.A. Point Source Emission Limits, and the methods utilized to mitigate emissions and restore normal operations.

3. Compliance with this malfunction notification provision shall not excuse or otherwise constitute a defense to any violation of this permit or any law or regulation such malfunction may cause.

E. RIGHT OF ENTRY

EPA authorized representatives, upon the presentation of credentials, shall be permitted:

1. to enter the premises where the facility is located or where any records are required to be kept under the terms and conditions of this PSD Permit;

2. during normal business hours, to have access to and to copy any records required to be kept under the terms and conditions of this PSD Permit;

3. to inspect any equipment, operation, or method subject to requirements in this PSD Permit; and,

4. to sample materials and emissions from the source(s).

F. TRANSFER OF OWNERSHIP

In the event of any changes in control or ownership of the facilities to be constructed under this PSD permit, this PSD permit is binding on all subsequent owners and operators. The Permittee shall notify, by letter, the succeeding owner and operator of the existence of this PSD permit and its conditions. A copy of the letter shall be provided to EPA within 30 days of the letter signature. Permit transfers shall be made in accordance with 40 CFR Part 122, Subpart D.

G. SEVERABILITY

The provisions of this PSD permit are severable, and, if any provision of the PSD permit is held invalid, the remainder of this PSD permit shall not be affected.

H. ADHERENCE TO APPLICATION AND COMPLIANCE WITH OTHER ENVIRONMENTAL LAWS

The Permittee shall construct and operate this project in compliance with this PSD permit, the application on which this PSD permit is based, and all other applicable federal, state, and local air quality regulations. This PSD permit does not release the Permittee from any liability for compliance with other applicable federal, state and local environmental laws and regulations, including the Clean Air Act.

I. BINDING APPLICATION

This permit is issued in reliance upon the accuracy and completeness of the information set forth in the Permittee's application to EPA dated August 2012, and subsequent information provided by the Permittee to EPA, as listed in the Administrative Record for issuance of this permit.

The Permittee shall abide by all representations, statements of intent and agreements contained in the permit application and subsequent submittals as listed in the Administrative Record. EPA shall be notified no less than 10 working days in advance of any significant deviation from the permit application, and shall furnish any plans, specifications or supporting data regarding such deviation. The issuance of this PSD permit to Construct and Operate may be suspended or revoked if EPA determines that a significant deviation from the permit application, specifications, and supporting data furnished has been, or is to be, made.

J. ENFORCEABILITY OF PERMIT

On the effective date of this permit, the conditions herein become enforceable by EPA pursuant to any remedies it now has or may have in the future, under the Clean Air Act.

K. TREATMENT OF EMISSIONS

Emissions in excess of the limits specified in this permit shall constitute a violation.

III. SPECIAL PERMIT CONDITIONS

A. POINT SOURCE EMISSION LIMITS

At all times after completion of the installation of the natural gas fired boiler, including during startup, shutdown and malfunction, the Permittee shall not allow the discharge of GHG emissions from the unit into the atmosphere, in excess of the following:

Table 1: Emission Limits

Emission Point/Equipment	Limitations
Foster Wheeler Model AG 5195, 254 MMBtu/hr natural gas fired boiler	• 125.3lb per MMBtu based on a 24 hour rolling average • 130,263 ton CO_{2e} /365 day based on 365-day rolling average

B. REQUIREMENTS FOR NATURAL GAS FIRED BOILER

1. Compliance with lb CO_{2e} /MMBtu BACT Emission Limit

The above listed emission unit shall demonstrate compliance with the lb CO_{2e}/MMBtu BACT emission limit by the following equation:

Equation 1

$$CO2 \geq (5.18\, x 10^{-7}\, x\, C_{CO2}\, x\, Q\, x\, 2204.62) \div (V_{Hi}\, x\, 1020)$$

Where:

$CO2$ =	24 hour rolling average limit in Special Condition III.A,
C_{CO2} =	Hourly average CO_2 concentration (% CO_2)
Q =	Hourly average stack gas volumetric flow rate (scfh)
$5.18\, x 10^{-7}$ =	Conversion factor (metric tons/scf/% CO_2)
2204.62 =	Conversion factor (lbs/metric tons)
1020 =	Conversion factor (MMBtu/Mscf)
V_{Hi} =	Hourly volumetric flow rate of natural gas to the boiler (Mscf)

2. **Compliance with ton CO_{2e} / 365 day BACT Emission Limit**

The above listed emission unit shall demonstrate compliance with the ton CO_{2e}/yr BACT emission limit by the following equation:

Equation 2

$$T_{CO2e} \geq \sum_{i=1}^{365} \frac{(W_{CO2e}\ x\ 1020\ x\ V_{Di})}{2000}$$

Where:

T_{CO2e} =	130,263 CO_{2e} ton/yr limit in Special Condition III.A, Table 1
W_{CO2e} =	117 lb CO_{2e}/MMBtu
1020 =	Conversion factor (MMBtu/Mscf)
V_{Di} =	Daily average volumetric flow rate of natural gas to the boiler (Mscf)
2000 =	Conversion factor (lb/ton)

3. **Work Practice and Operational Requirements**

a. To demonstrate compliance with the BACT emission limits the Permittee shall calculate the lb CO2e/MMBtu at least once every day. The Permittee shall monitor and record hourly average CO_2 concentrations (% CO_2) and hourly average stack gas volumetric flow rate (scfh) from the boiler at least once a day. The Permittee shall monitor and record the hourly volumetric flow rate of natural gas to the boiler (Mscf) at least once per hour.

b. Compliance with the 365-day rolling average ton CO_{2e}/365-day BACT emission limit shall be determined at least once every day after 365 days of data have been recorded. The Permittee shall monitor and record the daily average volumetric flow rate of natural gas to the boiler (Mscf) at least once a day

c. The Permittee shall compare the calculated CO_{2e} emissions from Special Condition III.B.1. Compliance with lb CO_{2e} /MMBtu BACT Emission Limit and Special Condition III.B.2. Compliance with ton CO_{2e} / 365 day BACT Emission Limit to the allowable BACT CO_{2e} limit required in Special Condition III.A Point Source Emission Limits. The calculated CO_{2e} emissions shall be less than the allowable BACT CO_{2e} limit. If the Permittee finds that the calculated CO_{2e} emissions rate is greater than the allowable BACT CO_{2e} limit, the Permittee shall review the operational performance of the emission unit and monitoring instrumentation. From this review, any necessary corrective measures shall be identified and recorded by the Permittee, including the reason for the CO_2 emissions difference. The Permittee shall complete corrective measures within 48 hours of identification of a difference and comply with Section IV., Recordkeeping Requirements.

d. The Permittee shall install, maintain and operate a non-resettable elapsed flow meter, to measure the flow rate of the fuel combusted in the natural gas fired boiler. Flow rate will be recorded at least once per hour, averaged daily, and recorded as Mscf.

e. The Permittee shall install, maintain and operate a continuous emission monitor (CEM) on the exit stack of the natural gas fired boiler to monitor hourly average CO_2 concentrations (% CO_2). Hourly average CO_2 concentrations will be recorded at least once per day and recorded as (% CO_2).

f. The Permittee shall install, maintain and operate a flow meter to measure the hourly average stack gas volumetric flow rate (scfh) exiting the natural gas fired boiler. This shall be recorded at least once per day and recorded as scf.

g. The Permittee shall install and maintain a minimum of 4 inches of insulation around the boiler at all times.

h. The Permittee shall install, maintain and operate NO_x control requirements as required by the Wyoming DEQ PSD permit for this boiler.

i. The Permittee shall install, maintain and operate during all times, a boiler blowdown tank and in-stack economizer.

j. The Permittee shall ensure that all ducting for boiler intake air draws air from at or above the process building roofline.

k. The Permittee shall ensure that the natural gas boiler is integrated into the existing Solvay steam production system.

l. The Permittee shall ensure that Maintenance and Operation requirements that include yearly steam line inspections, maximized condensate recovery and usage of an anti-scalant additive to the boiler feed water are established and implemented for this natural gas fired boiler.

m. The Permittee shall maintain and operate the emission unit to ensure the GHG emissions are continuously at or below the emissions limits specified in this permit.

IV. RECORDKEEPING REQUIREMENTS

A. Including any recordkeeping requirements specified elsewhere in this permit, the Permittee shall maintain a file of all records, data, measurements, reports, and documents related to the operation of this boiler, including, but not limited to, the following: all records or reports pertaining to significant maintenance performed on any system or device related to the operation of this boiler; all records relating to performance tests and monitoring of auxiliary combustion equipment; and other information required by this permit recorded in a permanent form suitable for inspection. The file must be retained for not less than 5 years following the date of such measurements, maintenance, reports, and/or records.

B. The Permittee shall maintain the following records for at least 5 years, including:

1. the occurrence and duration of any startup, shutdown, malfunction;

2. duration of any initial shakedown period for the emission unit;

3. calibration tests of flow meters required by Condition V.A. Performance Testing Requirements used to demonstrate compliance with this permit;

4. the time and duration of any periods that monitoring devices are not operating;

5. all data recorded in compliance with Special Conditions III.B.1. Compliance with lb CO_{2e} /MMBtu BACT Emission Limit through III.B.3. Work Practice and Operational Requirements; and

6. all CEMs testing, maintenance, and calibration checks conducted to satisfy quality assurance requirements under Condition V.B. Performance Testing Requirements.

C. The Permittee shall maintain records of any exceedance of limitations in this permit and submit a written report of all exceedances to EPA semi-annually except when: more frequent reporting is specifically required by an applicable subpart; or the authorized representative of the Administrator, on a case-by-case basis, determines that more frequent reporting is necessary to accurately assess the compliance status of the source. The report is due on the 30th day following the end of each semi-annual period and shall include the following:

1. time intervals, data and magnitude of the exceedance, the nature and cause (if known), corrective actions taken and preventative measures adopted;

2. applicable time and date of each period during which the monitoring equipment was inoperative (monitoring down-time);

3. if no exceedances of a permit limit occurred during the reporting period or the monitoring equipment has not been inoperative, repaired or adjusted, a statement that no exceedance of that limit occurred, and/or that the monitoring equipment has not been inoperative, repaired or adjusted (as applicable), shall be submitted;

4. any failure to conduct any required source testing, monitoring, or other compliance activities; and

5. any violation of limitations on operation, including but not limited to restrictions on hours of operation of the emergency generator.

D. Exceedance shall be defined as any period in which the facility emissions or other parameter of operation exceed a maximum limit set forth in this permit.

E. Excess emissions indicated by GHG emission source certification testing or compliance monitoring shall be considered violations of the applicable emission limit for the purpose of this permit.

F. All records required by this PSD Permit shall be retained for not less than 5 years following the date of such measurements, maintenance, and reports.

V. PERFORMANCE TESTING REQUIREMENTS

A. The Permittee shall calibrate, according to manufacturer's specifications, all flow meters used to comply with Special Condition III.B.3.d. Work Practice and Operational Requirements at least once per calendar year.

B. The Permittee shall calibrate daily the CEM used to comply with Special Condition III.B.3.e. Work Practice and Operational Requirements, according to manufacturer's specifications. In addition, the Permittee shall perform a relative accuracy test audit of the CEM used to comply with Special Condition III.B.3.e. Work Practice and Operational Requirements at least once per calendar year. This test audit shall be conducted under the procedures described in 40 CFR Part 60, Appendix F.

C. The Permittee shall maintain records of all performance tests as required under Special Condition IV. A. 6. Recordkeeping Requirements.

VI. AGENCY NOTIFICATIONS

A. The Permittee shall submit GHG permit applications, permit amendments, and other applicable permit information to:

Air Program (8P-AR)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

B. The Permittee shall submit a copy of all compliance and enforcement correspondence as required by this permit to:

Air Technical Enforcement Program (8ENF-AT)
US EPA Region 8
1595 Wynkoop St.
Denver, CO 80202

C. For any notifications required to be delivered to EPA within a certain time frame, fulfillment of the requirement can be accomplished by delivery of the required information to EPA in writing, postmarked by such date.

Authorized By: United States Environmental Protection Agency, Region 8

Debra H. Thomas
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance (OPRA)

Date: 1/27/14

Statement of Basis
Greenhouse Gas Prevention of Significant Deterioration Pre-Construction Permit
for the Solvay Soda Ash Joint Venture,
Green River Soda Ash Plant

Permit Number: PSD-WY-000004-2012.001

DATE January 27, 2014

This document serves as the Statement of Basis (SOB) required by 40 CFR 124.7. This document sets forth the legal and factual basis for the permit conditions and provides references to the statutory or regulatory provisions, including provisions under 40 CFR 52.21, and 40 CFR 52.37 (Federal Implementation Plan (FIP) to issue permits under the Prevention of Significant Deterioration (PSD) requirements to sources in certain states that emit greenhouse gases), that apply to this permit. This document is intended for use by all parties interested in the permit.

I. Executive Summary

In August, 2012, Solvay Soda Ash Joint Venture (Solvay) submitted to the Environmental Protection Agency Region 8 (EPA) a PSD permit application for a Greenhouse Gas (GHG) emissions permit associated with the modification of its Green River soda ash facility located near Green River, Wyoming. Additional information was submitted on August 12, 2013. In connection with the same proposed project, Solvay submitted a PSD permit application for non-GHG pollutants to the Wyoming Department of Environmental Quality (WDEQ) Air Quality Division (AQD). The proposed modifications are intended to de-bottleneck the facility's soda ash and related products production circuits. This involves adding a steam boiler, which will be the only new source of air emissions. The de-bottlenecking will also include adding a heat exchanger, which will utilize available steam heat for the purpose of speeding up the crystallization processes. The combination of adding the steam boiler and heat exchanger will serve to increase both short-term and long-term production while remaining within the previously permitted design rates. After reviewing the application, EPA prepared a SOB and a draft New Source Review (NSR)/PSD pre-construction air permit to authorize construction of a GHG air emission source at the Solvay facility.

This SOB documents the information and analysis EPA used to support decisions made in drafting and issuing of the air permit. It includes a description of the proposed facility, the applicable air permit requirements, and an analysis showing how the applicant complied with the requirements.

Solvay submitted additional information on August 12, 2013 to EPA. This submittal contained information to assist EPA in making determinations applicable to the Endangered Species Act (ESA) Section 7, National Historic Preservation Act (NHPA) Section 106, and issues relating to Environmental Justice (EJ).

EPA concludes that Solvay's application is complete and provides the necessary information to demonstrate that the proposed project meets the applicable PSD air permit regulations for GHG. EPA's initial conclusions rely upon information provided in the permit application, supplemental information submitted to EPA by Solvay in response to EPA's request, and EPA's own technical analysis. EPA is making all of this information available as part of the public record for the permit application.

II. Applicant

Solvay Soda Ash Joint Venture
Green River Soda Ash Plant
P. O. Box 1167
Green River, WY 82935

Physical Location:
Green River Soda Ash Plant
NE Quarter, Section 31, Township 18 North, Range 109 West
Sweetwater County, Wyoming

Owner/Operator:
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant

Responsible Official: Mr. Ronald O. Hughes, (307) 875-6500
Permit Contact: Mr. Tim Brown, (307) 875-6500

III. Permitting Authority

On December 30, 2010, EPA published a FIP making EPA the GHG PSD permitting authority for states that do not have the authority to implement GHG PSD permitting. 75 FR 82246 (promulgating 40 CFR 52.37). Wyoming still retains approval of its State Implementation Plan (SIP) and PSD program for pollutants that were subject to regulation before January 2, 2011, i.e., regulated NSR pollutants other than GHGs.

The GHG PSD permitting authority for the state of Wyoming is:

EPA, Region 8
1595 Wynkoop St.
Denver, CO 80202

Permit Author:
Donald Law
Air Permitting Monitoring and Modeling Unit (8P-AR)
(303) 312-7015

The non-GHG PSD permitting authority for the state of Wyoming is:

Air Quality Division
Wyoming Dept. of Environmental Quality
122 West 25th Street
Cheyenne, WY 82002

IV. Public Notice, Comment, Hearings and Appeals

Public notice for the draft PSD GHG permit was published on December 12, 2013, in the Rock Springs Rocket-Miner. The public comment period began on December 12, 2013 and closed on January 13, 2014, at 8:30 p.m. During the public comment period, the public was given the opportunity to review a copy of the permit application, the draft permit prepared by EPA, the SOB, and permit-related correspondence. The draft permit, SOB, and Administrative Record for the draft permit were available for review at EPA Region 8's office Monday through Friday, from 8:00 a.m. to 4:00 p.m. (excluding federal holidays). The permit application, draft permit and SOB were also available for review on EPA's website at http://www.epa.gov/region8/pubnotice.html, under the heading "Region 8 Air Permitting comment opportunities" within the "PSD Permits" heading. A hardcopy of these documents was available for review at the Sweetwater County Clerk's Office in Green River, Wyoming, Monday through Friday from 8:00 a.m. to 5:00 p.m. until the close of the public comment period.

In accordance with 40 CFR 52.21(q), *Public participation*, any interested person was afforded the opportunity to submit written comments on the draft permit during the public comment period and to request a hearing. Since the EPA is not the permitting authority for the remainder of the NSR pollutants, a public hearing regarding the WDEQ draft PSD permit would not be covered by a public hearing on the EPA GHG permit. No public hearing was requested for this action.

In accordance with 40 CFR 124.13, *Obligation to raise issues and provide information during the public comment period*, anyone, including the permit applicant, who believes any condition of the draft permit is inappropriate, or that EPA's tentative decision to prepare a draft permit for the project is inappropriate, must raise all reasonably ascertainable issues and submit all arguments supporting the commenter's decision, by the close of the public comment period. There were no comments submitted for this permit.

In accordance with 40 CFR 124.15, *Issuance and Effective Date of Permit*, the permit shall become effective immediately upon issuance as a final permit, if no comments request a change in the draft permit. If changes are requested, the permit shall become effective thirty days after issuance of a final permit decision. Notice of the final permit decision shall be provided to the permit applicant and to each person who submitted written comments or requested notice of the final permit decision. No public comments were received for this permit. Therefore, the permit will be effective upon issuance.

In accordance with 40 CFR 124.19, *Appeal of RCRA, UIC, and PSD Permits*, any person who filed comments on the draft permit or participated in the public hearing may petition the Environmental Appeals Board, within 30 days after the final permit decision, to review any condition of the permit decision. Any person who failed to file comments or failed to participate in the public hearing on the draft permit may petition for administrative review only on changes from the draft to the final permit decision. There were no changes from the draft to the final permit.

V. Facility Location

The Solvay facility is located in Sweetwater County, Wyoming. A portion of Sweetwater county is currently designated as non-attainment for the ozone National Ambient Air Quality Standard (NAAQS). However, the Solvay facility is not located within this non-attainment area. The portion of Sweetwater county where the Solvay facility is located is currently considered to be in attainment for all of NAAQS. The nearest federal Class 1 area is Bridger Wilderness Area. The geographic coordinates for this facility are as follows:

NE Quarter, Section 31, Township 18N, Range 109W
Latitude 41.501, Longitude -109.758

VI. Applicability of Prevention of Significant Deterioration (PSD) Regulations

Under EPA's Clean Air Act permitting rules, the term "greenhouse gas" means an air pollutant consisting of the aggregate of six gases with atmospheric warming potential: carbon dioxide (CO_2), methane (CH_4), nitrous oxide (N_2O), hydrofluorocarbons (HFCs), perfluorocarbons (PFCs), and sulfur hexafluoride (SF_6). GHG emissions are determined by multiplying the mass emissions of each of these gases, in tons per year (tpy) by its respective Global Warming Potential (GWP) and summing the result, which is referred to as the "CO_2-equivalent" (CO_{2e}). The GWPs (40 CFR 98, Table A-1) are 1.0 for CO_2, 25 for CH_4, and 298 for N_2O. No emissions of HFCs, SF_6 or PFCs are expected from this project.

EPA concludes that Solvay's application is subject to PSD review for GHG because the project would lead to a GHG emissions increase as described at 40 CFR § 52.21(b)(49)(iv). The proposed project emissions would result in increased GHG emissions above both of the PSD applicability thresholds, which are 0 tpy on a mass basis and 75,000 tpy on a CO_2e basis. Solvay has presented CO_2e potential mass emissions of 130,290 tpy for this project. The project's potential GHG emissions on a mass basis are 130,049 tpy. EPA is the permitting authority responsible for implementing a GHG PSD FIP for Wyoming under the provisions of 40 CFR § 52.21 (except paragraph (a)(1)). See 40 CFR § 52.37.

As the permitting authority for regulated NSR pollutants other than GHGs, WDEQ has determined the proposed project is subject to PSD review for non-GHG pollutants. Specifically, the PSD application submitted to WDEQ explains the proposed facility will be a major modification to an existing major stationary source. Accordingly, WDEQ will issue the non-GHG portion of the PSD permit and EPA Region 8 will issue the GHG portion.[1]

As part of its analysis, EPA considers the policies and practices reflected in the EPA document entitled "PSD and Title V Permitting Guidance for Greenhouse Gases" (March 2011) (Guidance), available on EPA website at: www.epa.gov/nsr/ghgdocs/ghgpermittingguidance.pdf. Consistent with the recommendations in that Guidance, we have not required the applicant to model or conduct ambient

[1] *See* EPA, Question and Answer Document: Issuing Permits for Sources with Dual PSD Permitting authorities (April 19, 2011), http://www.epa.gov/nsr/ghgdocs/ghgissuedualpermitting.pdf

monitoring for GHG, since there are no ambient air quality standards for GHGs, and we have not required any assessment of impacts of GHG in the context of the additional impacts analysis or Class I area provisions. Instead, EPA has determined that compliance with the Best Available Control Technology (BACT) analysis is the best technique that can be employed, at present, to satisfy the additional impacts analysis and Class I area requirements of the rules related to GHG. We note again, however, that the project has triggered review for regulated NSR pollutants that are non-GHG pollutants under the PSD permit sought from WDEQ.

For a description of the five-step process involved in making a PSD BACT determination for GHGs, please refer to the aforementioned Guidance and sources there cited. EPA has followed those steps in making the GHG BACT initial determination for this project.

VII. Project Description

The Solvay natural gas boiler project proposes to construct a new natural gas fired boiler that will add steam-generating capacity to the Solvay facility. The addition of this natural gas fired boiler with the two existing coal-fueled boilers will allow Solvay the operational flexibility to (1) shut any one of the three boilers down for maintenance without curtailing production, and (2) take advantage of the lower-cost fuel (coal vs. natural gas).

With this project, Solvay expects to increase annual soda ash production by approximately 14 percent. This permit modification assumes no operational limit on combined steam production, and the additional boiler will be permitted to operate at capacity. In this way, the gas-fueled boiler could run at its maximum while the coal boilers would supplement as needed, or the coal-fueled boilers could operate at their capacity while the gas boiler would supplement the steam demand.

This additional boiler is a water tube package natural gas fired, 254 MMBtu/hr boiler (Foster Wheeler Model AG 5195) that was installed previously in Garfield County, Colorado at the American Soda facility. It was used from 2000 through May 2004 and then permanently shut down. It is a boiler capable of producing 200,000 lbs. of steam per hour, to be added in parallel to the two 300,000 lbs. per hour coal boilers. In 2003, Solvay purchased the American Soda facility in Garfield County, Colorado, including the Foster Wheeler Model AG 5195 natural gas fired boiler. The boiler will be fueled through the Western Gas Pipeline by a spur currently feeding the Solvay plant.

Short-term production capacity will not change, although the addition of the heat exchanger will allow short-term actual production to increase and come nearer to capacity. On an annual basis, this additional steam production will enable the plant to continue production during boiler maintenance so there can also be an increase in long-term actual production. Solvay anticipates actual annual soda ash production to increase by 360,000 tons from the current actual level of 2.55 to 2.91 million tons. Depending on the mix of boiler use between coal and gas, the group of boilers' criteria pollutants and CO_2e emissions could increase. The gas boiler emissions are lower on a per-unit-of-steam-basis than the emissions from the coal boilers. If the gas boiler were to operate at capacity with the coal boilers cut back, boiler emissions of at least NO_x, and CO_2e would decrease. Emissions from the other existing fueled sources, which are the calciners and some dryers, could increase with increased production since they operate in series with the steam-heated crystallizers.

Table 1 – GHG Emissions from Solvay Project

GHG	Mass Emissions, tpy	Global Warming Potential	Project GHG emissions (as CO_2e, tpy)
Carbon Dioxide (CO_2)	130,041	1	130,041
Methane (CH_4)	6.97	25	174
Nitrous Oxide (N_2O)	0.25	298	75
Project Emissions, tpy	130,049		130,290

VIII. BACT Analysis

The BACT analysis provided by the applicant included the assumptions described below, which have been considered and modified by EPA in its own BACT analysis.

1. Table 1 presents estimated Solvay GHG emissions in terms of CO_2e emissions, and only includes emissions of CO_2, CH_4, and N_2O. The project is not expected to emit HFCs or PFCs because these man-made gases are primarily used as cooling, cleaning, or propellant agents.

2. From the GHG emissions inventory presented in Table 1 above, CH_4 and N_2O total only approximately 222 tpy of CO_2e emissions, which is about 0.17% of total CO_2e emissions. As this project is primarily considering options to bolster energy efficiency at the facility and reductions in CO_2 relate to fuel usage that also provides a reduction of CH_4 and N_2O, this permit will examine the CO_2 emissions as essentially a surrogate for CO_2e.

The project will include one new GHG-emitting emission unit that is subject to BACT: the Foster Wheeler 254 MMBtu/hr natural gas fired boiler.

Foster Wheeler 254 MMBtu/hr Boiler CO_2 Emissions

Step 1 Identify Potential Control Technologies

In discussions with EPA about the use of the existing, owned, and available boiler, Solvay stated that the proposed unit is a 10+ year old Foster-Wheeler unit. Information supplied by Foster Wheeler indicates that this proposed unit is designed to operate at 83-85% efficiency at high heating value and that a new unit of the same size and current technology would have a similar design efficiency (83-85%). Given this similarity in beginning efficiency, a new boiler will not be considered as a possible BACT option for this project.

The gas-fueled boiler is being added to the Solvay plant to supplement the steam provided by existing coal-fueled boilers, but it could also be used as a base load while varying the steam production of the coal-fueled boilers to meet capacity. In this way, the CO_2e would be reduced because the GWP per unit of heat from coal is higher than the CO_2e for heat from natural gas (94 kg CO_2/MMBtu v 53 kg CO_2/MMBtu). Solvay asserts that the flexibility to use the boilers as best meets the needs of the plant is its choice and that the BACT analysis does not extend to this level of controlling the mix of boiler usage. EPA agrees with Solvay's need for operational flexibility.

Technology related to maximizing steam boiler energy efficiency is provided in the ICI Boiler Manual, which addresses feasible efficiency-increase technologies as a surrogate for CO_2 control technologies for steam boilers. At 254 MMBtu per hour, the Solvay boiler fits well within the class of ICI boilers addressed. Table 2 lists the entries as feasible options for maximizing energy efficiency. Solvay grouped the methods of increasing thermal efficiency from a boiler as follows: 1) Efficient design of boiler and associated steam delivery equipment, 2) Efficient operation of equipment, 3) Good maintenance, and 4) Other measures.

TABLE 2: BACT Control Options

Group	BACT Option	Technical Feasibility	Description
Efficient Boiler Design and Steam Delivery			
	High Efficiency Burner	Yes	Ultra-Low NOx Burner (UNLB) is part of the design.
	Refractory Material Selection	Yes	Best available already included in boiler design.
	Economizer Usage	Yes	Part of Boiler Design. Exhaust temp of 320 F or less.
	Blowdown Heat Recovery	Yes	Blowdown sent to flash tank as part of boiler design.
	Condensate Recovery For Boiler Reuse	Yes	Maximum amount the steam circuit will accept based on water quality requirements. All condensate is recovered for use in the plant.
	Combustion Air-Preheater	Yes	Combustion air is drawn from the process building roof line which is approximately 20 F warmer than building ground level air.
	Increased Boiler Insulation	Yes	Boiler designed for 3 inches. Solvay agrees to install additional insulation to achieve at least 4 inches.
	Increased Refractory Lining	No	Additional Refractory Lining would require boiler redesign.

Efficient Operation of the Boiler and Steam Distribution Equipment			
	Energy Management Systems	Yes	Boiler will be connected into the current steam management system and will be controlled by Solvay's current energy management system.
	Good O&M Practices	Yes	
	Boiler Instrumentation and Control	Yes	Additional control is included with ULNB to meet NOx & CO emission limits.
Good Maintenance			
	Steam Line Maintenance	Yes	Scaling to be controlled with anti-sealant additive. Pipes to be visually checked at least quarterly and insulation replaced as needed.
	Minimization of Air Infiltration	No	
	Minimization of Gas-side Heat Transfer Deposits	No	
	Minimize Steam Trap Leaks	Yes	Inspected and repaired at least annually.
Other Measures			
	Turbine Shaft Power Extracted from High Pressure Steam	Yes	Included in existing steam circuit. There are 9 turbines powering 4 ducted fans and 5 pumps. Turbines eliminate use of electrical power.
	Carbon Capture and Storage	Yes	

Step 2 Eliminate Technically Infeasible Options

This step of the top-down BACT analysis eliminates from consideration any technically infeasible options. EPA generally considers a technology to be technically feasible if it: (1) has been demonstrated and operated successfully on the same type of source under review, or (2) is "available" and "applicable" to the source type under review. See Guidance at 33. To be considered available, a technology must have reached the licensing and commercial demonstration phase of its development. Applicability is based on source-specific factors and physical, chemical, and engineering principles that preclude safe and successful operation of a control option at a specific location.

Efficient Boiler Design and Steam Delivery

Within the Efficient Boiler Design and Steam Delivery grouping, Solvay indicated that increasing the thickness of the refractory lining was technically infeasible. As this boiler is already owned by Solvay but located at a different facility, it would be impossible to specify refractory thickness as a part of this boiler design. As such, EPA agrees with Solvay that increasing the refractory thickness is technically infeasible for this project.

Good Maintenance

Minimization of Air Infiltration

At EPA's request, Solvay provided additional information on August 12, 2013 concerning their claim that minimizing air infiltration is not technical feasible for the project's boiler. Solvay's natural gas boiler will operate at positive pressure (18.51 inches of water.) Therefore, the boiler will operate at a pressure higher than the environment surrounding the boiler. When the boiler is operating, the higher pressure air from the boiler will exert outward forces from the boiler which would eliminate air infiltration into the boiler. Due to this boiler design, EPA agrees that minimization of air infiltration is not technically feasible as a BACT option.

Minimization of Gas-side Heat Transfer Deposits

Solvay provided additional information on August 12, 2013 concerning their claim that minimizing gas-side heat transfer deposits is not technically feasible for the project's boiler. The build-up of deposits on the gas-side of the heat transfer tubes within a boiler occurs due to the presence of long chain hydrocarbons within the gas stream. Due to the composition of natural gas, the build-up of these deposits on the gas-side of the heat transfer tubes is not to be expected. Therefore, EPA agrees that minimization of gas-side heat transfer deposits is not applicable here, and is not considering it.

Other Measures

Carbon Capture and Storage

CCS technology is composed of 3 main components: (1) CO_2 capture, including compression; (2) CO_2 transport, and; (3) permanent CO_2 storage or sequestration.

CCS systems involve the use of adsorption or absorption processes to separate and capture CO_2 from the flue gas, with subsequent desorption to produce a concentrated CO_2 stream. The concentrated CO_2 is then compressed to "supercritical" temperature and pressure, a state in which CO_2 exists neither as a liquid nor a gas, but instead has physical properties of both liquids and gases. The supercritical CO_2 would then be transported to an appropriate location for underground injection into a suitable geological storage reservoir, such as a deep saline aquifer or depleted coal seam, or used in crude oil production for enhanced oil recovery (EOR) or through ocean sequestration.

The capture of CO_2 from the gas streams can be accomplished using either physical or chemical solvents or solid sorbents. Applicability of different processes to particular applications will depend on temperature, pressure, CO_2 concentration, and contaminants in the gas or exhaust stream.

After separation, the CO_2 must be compressed to supercritical temperature and pressure for suitable pipeline transport. While compressor systems for such applications are proven and commercially available, the technologies require specialized equipment and the operating energy requirements are very high.

The supercritical CO_2 would then be transported to an appropriate location for injection into a suitable storage reservoir. The transport options may include pipeline or truck transport, or in the case of ocean storage, transport by oceangoing vessels.

CO_2 storage methods include geologic sequestration, oceanic storage, and mineral carbonation. Oceanic storage, as discussed below, has not been demonstrated in practice and is not currently practical to CO_2 captured in Wyoming. Geologic sequestration is the process of injecting captured CO_2 into deep subsurface rock formations for long-term storage, which includes the use of a deep saline aquifer or depleted coal seams, as well as the use of compressed CO_2 to EOR in crude oil production operations.

Under geologic sequestration, a suitable geological formation is identified close to the project location and the captured CO_2 from the process is compressed and transported to the sequestration location. CO_2 is injected into that formation at a high pressure and to depths generally greater than 2,625 feet (800 meters).

Below this depth, the pressurized CO_2 remains "supercritical" and behaves like a liquid. Supercritical CO_2 is denser and takes up less space than gaseous CO_2. Once injected, the CO_2 occupies pore spaces in the surrounding rock, like water in a sponge. Saline water, which already resides in the pore space would be displaced by the denser CO_2. Over time, the CO_2 can dissolve in residual water and chemical reactions between the dissolved CO_2 and rock can create solid carbonate minerals, more permanently trapping the CO_2.

There are several geologic formations identified across Wyoming that might provide a suitable site for geologic sequestration. Based on the NETL 2010 Big Sky Carbon Sequestration Partnership (BSCSP) atlas, potentially suitable sequestration basins are located immediately in the vicinity of Green River and Rock Springs, Wyoming, providing potentially feasible deep saline formations (NETL, 2010). However no exploratory work or injection pilot testing into the geological formations near these areas has been conducted to date, so the actual suitability of these formations is unknown.

According to NETL/BSCSP, there are no active CCS projects operating within Wyoming, making the logistical and capital costs unclear as to the efficient use of these basins. Further, the geotechnical analyses needed to confirm their suitability have not been conducted. As such, the analysis of transport options must consider long distances potentially required to reach existing storage locations.

Ocean storage is accomplished by injecting CO_2 into the ocean water typically below 1,000 meters via pipe or ship. At these depths, CO_2 is expected to dissolve or form into a horizontal lens which would delay the dissolution of CO_2 into the surrounding environment. The depth of the overlying water and the lensing of the CO_2 will form a natural impediment to the vertical movement of the injected CO_2.
In mineral carbonation, captured CO_2 is reacted with metal-oxide bearing materials, thus forming the corresponding carbonates and a solid byproduct.

Geological sequestration of CO_2 through EOR is relatively well understood and is being implemented at full scale at many locations across the U.S. According to the CCS Interagency Task force "approximately 50 million tons of CO_2 per year are injected, produced with oil, captured, and re-injected" (ICCS, 2010). EOR consists of injecting CO_2 into an existing oil field where it can mix with crude oil, causing the conditions for additional pressure and ability to extract oil from otherwise diminished production sites. CO_2 is then extracted from the crude oil produced and re-injected into the formation to maintain constant recovery rates. Limiting factors to EOR include transportation of captured CO_2 to available oil field operations and the availability of infrastructure to do so.

Sequestration of available CO_2 through mineral carbonation can be accomplished by combining CO_2 with available calcium or magnesium carbonates, such as serpentine or olivine to form carbonate minerals such as calcite, dolomite, and magnesite. The process is accomplished in an industrial (ex situ) setting or in situ by injecting into mineral rich deposits. Mineral carbonation has been studied for some time and the research into the practical implementation as a sequestration technology is on-going. Challenges include slow kinetic reactions, proximity of available mineral deposits to CCS operations, and the large volume of energy required to drive the carbonation process.

Solvay's initial GHG PSD application considered CCS to be technically infeasible for this project. EPA recognizes some of the technical and logistical challenges of a CCS system for the Solvay boiler project; however, EPA considers CCS as a technically feasible option.

Step 3 Rank Remaining Control Technologies by Control Effectiveness.

Due to the nature of the BACT options considered for this project, a control effectiveness ranking was not done for this project. Any BACT option determined to be cost effective and technically feasible will be selected for this project.

Step 4 Evaluate Economic, Energy and Environmental Impacts.
Carbon Capture and Storage

Solvay supplied additional information to EPA discussing the economic viability of CCS applicability to their project. This information was submitted in August 2013. In its supplemental submission, Solvay utilized cost estimates from another similar project at the Solvay facility, referred to as the MEA CO_2 Extraction Project (MEA project). For the MEA project, Solvay considered the cost of capturing/removing CO_2 (post-combustion) from one of its two coal-fired boilers at the facility. The MEA project cost included CO_2 capture, but did not include compression, transportation, and storage of CO_2, therefore providing a low-end (conservative) estimate of CCS costs for the natural gas boiler project.

Union Engineering estimated costs for removal of ~118,000 tpy CO_2 from the Solvay coal boiler flue gases with a 10.6 percent concentration of CO_2 in the exhaust stream. For comparison, the CO_2 emissions available from capture from Solvay's natural gas boiler are ~130,000 tpy CO_2 at capacity with CO_2 flue gas concentrations around six percent. The MEA project was designed to remove approximately 90 percent of the mass of CO_2 of the current boiler project, so the projects are similar in size.

Attachment B, Page 1of the August 2013 Supplement provides Solvay's total cost estimate of $25,675,625 for the MEA CO_2 capture project. These total project capital costs include the costs of materials, equipment, construction, services, operating expenses, and project contingencies. Attachment B, Pages 2 through 26, provide a budget quote from Union Engineering for the CO_2 capture equipment package which is included in the total MEA project costs. These costs do not include any costs associated with compression, transportation, or CO_2 storage.

As provided in Attachment C of the August 2013 Supplement, Solvay estimates the total cost of the natural gas boiler project at $12,506,350. This is the same cost used by management in the past to determine the production viability of the project for production economics purposes.

Therefore, the estimated post-combustion capture capital costs for the MEA CO_2 capture project ($25,675,625) are roughly twice the total capital costs of the natural gas boiler project ($12,506,350). EPA expects that overall CCS costs associated with reduced CO_2 capture (e.g., less than 90%) for the natural gas boiler project would not be appreciably different for this size and type of boiler. For the Sinclair Refinery GHG PSD project, EPA determined that a post-combustion capture cost to project cost ratio of 0.71 was financially prohibitive. Solvay's capture cost to project cost ratio of 2.05 is nearly three times higher than the Sinclair Refinery project, and these costs do not consider the additional costs of compressing, transporting, and storing the CO_2. Furthermore, there are additional energy requirements to operate a CO_2 capture and compression system that would increase the overall cost of the CCS system, and potentially increase emissions of other pollutants. As such, CCS is rejected under Step 4 of the BACT analysis for its natural gas boiler project.

Non-CCS Control Options

All non-CCS control options under consideration in Step 1 of the BACT analysis are either technically feasible or they have acceptable economic, energy, or environmental impacts.

Step 5 Select BACT and Document Results

BACT for the Solvay natural gas boiler project will include all of the following:

- A minimum of 4 inches of insulation on all insulated boiler components;
- NOx controls as required by the Wyoming PSD permit for this project;
- Installation and usage of a boiler blowdown tank and in-stack economizer;
- Ducting of boiler intake air from the process building roofline;
- Integration of this boiler into the existing Solvay steam production system; and
- Maintenance and Operation requirements that include yearly steam line inspections, maximized condensate recovery and usage of an anti-scalant additive to the boiler feed water.

The initial Solvay GHG permit application stated that Ultra-Low NOx burners would be used on the boiler as NOx control. However, at the time this document was written, the criteria pollutant PSD permit for this project had not yet been finalized by WDEQ. Therefore, the BACT for GHG will include the NOx controls that will be required by WDEQ and stated in the WDEQ permit.

In addition, Solvay proposes a long and short-term emission limit for CO_2e. Proposed limits are 130,263 tons per year, and 125.3lb per MMBtu, (HHV) respectively.

For the long-term limit, the maximum annual CO_2e emissions are proposed to be the emissions using the boiler Manufacturer Capacity Rating (MCR) which is 254 MMBtu/hr, boiler operation for 365 days/yr., and nominal natural gas quality emissions provided by EPA in 40 CFR Part 98, Subpart C, Table C-1. That nominal value is a CO_2e emission factor of 117 lb / MMBtu. This estimation calculation is shown in Appendix D of the August 2012 PSD application and results in an annual emission limit of 130,263 tons per year.

The short-term (hourly) CO_2e limit will be in the form of a mass of CO_2e per unit of energy input to the boiler. Pipeline gas is primarily composed of methane, but can have varying percentages of the hydrocarbon constituents (methane, ethane, propane, butane, pentane and hexane, etc) and also varying percentages of CO_2 among other passive constituents. The boiler manufacturer provided Solvay an estimate of the maximum heat content pipeline fuel that the boiler could experience in NW Colorado and this fuel analysis is presented on page 2 of Appendix A of the August 2012 PSD application. EPA believes that the qualities of the natural gas available in Sweetwater County, Wyoming are significantly similar enough to the natural gas available in NW Colorado for this estimate to remain accurate for this analysis. The CO_2 emissions associated with this gas composition are estimated on the final page of Appendix D August 2012 PSD application, using the constituent-specific CO_2 emissions per unit mass of the constituent and assembling these according to the quantity of the constituent in that fuel analysis. The CH_4 and N_2O components in the exhaust are expected to be approximately the same as for nominal natural gas and these fixed factors are added to the measured CO_2 to determine the total CO_2e short-term emission limit. These factors are 0.05 and 0.07lb/MMBtu respectively.

The CO_2 measurement will be by continuous emission monitor for exhaust concentration and associated with a continuously measured flow rate using Equation C-6 of 40 CFR Part 98.33 (a)(4)(ii). Using this method, the Solvay short-term limit is 125.3 lb CO_2e per MMBtu heat input. This is 7 percent higher than the nominal pipeline natural gas value of 116.9lb CO_2e per MMBtu.

For purposes of demonstrating compliance on a short-term basis, a boiler heat input is needed. This will be achieved by measurement of the volume of fuel consumed by the boiler and coupling it with a Solvay monitored heat content.

Thus, there are three independent measurements being made using different plant control systems, CO_2 concentration, and exhaust flow rate from emissions monitoring, and boiler heat input from process controls. Solvay states that the shortest time interval over which this will be a meaningful calculation would be 24 hours, using hourly averaged or totaled measurements. Hourly calculations would likely contain inconsistencies because all the measurements would not have been collected at the same time, and, Solvay expects some hysteresis in the furnace response to fuel feed. In addition, the CO_2 and flow rate monitors could create additional inconsistency, so that the three combined may not track hour by hour. Solvay requests that the short-term CO_2 measurement be tracked on a 24-hour totalized basis. The estimate of CO_2e emissions per unit of heat input will be calculated and compared with the compliance limit every calendar day.

EPA agrees with these limits. However, the yearly limit will be calculated on a 365 day rolling average rather than a yearly basis and the short term limit will be calculated on a 24 hour average basis.

IX. Environmental Justice (EJ), Endangered Species Act (ESA), and National Historic Preservation Act (NHPA)

Executive Order (EO) 12898 (59 FR 7629 (Feb. 16, 1994)) establishes federal executive branch policy on EJ. Based on this Executive Order, the EPA's Environmental Appeals Board (EAB) has held that EJ issues must be considered in connection with the issuance of federal PSD permits issued by EPA Regional Offices [See, e.g., *In re Prairie State Generating Company*, 13 E.A.D. 1, 123 (EAB 2006); *In re Knauf Fiber Glass*, Gmbh, 8 E.A.D. 121, 174-75 (EAB 1999)]. This permitting action authorizes emissions of GHG, controlled by what we have determined is the BACT for those emissions. It does not select environmental controls for any other pollutants. Unlike the criteria pollutants for which EPA has historically issued PSD permits, there is no NAAQS for GHG. The global climate-change inducing effects of GHG emissions, according to the "Endangerment and Cause or Contribute Finding", are far-reaching and multi-dimensional (75 FR 66497). Climate change modeling and evaluations of risks and impacts are typically conducted for changes in emissions that are orders of magnitude larger than the emissions from individual projects that might be analyzed in PSD permit reviews. Quantifying the exact impacts attributable to a specific GHG source obtaining a permit in specific places and points would not be possible [PSD and Title V Permitting Guidance for GHGs at 48]. Thus, we conclude it would not be meaningful to evaluate impacts of GHG emissions on a local community in the context of a single permit. Accordingly, we have determined an EJ analysis is not necessary for the permitting record.

The EPA has reviewed the proposed action for potential impacts on historic properties in the area of potential effect (APE). Based on our review of information from the permit applicant, National Park Service National Register of Historic Places and the Wyoming State Historic Preservation Office, we have determined that the proposed action should not affect any properties listed on the National Register of Historic Places. As presently designed, the proposed project will have no effect on known cultural resources. The results of the field inspection indicated that no new or previously identified cultural resources are located within the project area. The EPA is making the finding of "*No historic properties affected*" for the APE.

The proposed modification will be constructed within the existing boundaries of the Solvay facility in previously disturbed areas. The EPA has concluded that the proposed GHG PSD permit action will have "*no effect*" on listed species or critical habitat. If an action agency determines that the federal action will have no effect on listed species or critical habitat, the agency will make a "*no effect*" determination. In that case, the action agency does not initiate consultation with the Fish and Wildlife Service and its obligations under Section 7 are complete.

X. Conclusion and Action

Based on the information supplied by Solvay, our review of the analyses in the GHG PSD Permit Application and our independent evaluation of the information contained in our Administrative Record, it is our determination that the proposed modification would employ BACT for GHG under the terms contained in the permit. Therefore, EPA is issuing Solvay a PSD permit for GHG for the described project, subject to the PSD permit conditions specified therein.

UNITED STATES ENVIRONMENTAL PROTECTION AGENCY
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Ref: 8P-AR

JAN 27 2014

CERTIFIED MAIL
RETURN RECEIPT REQUESTED

Mr. Tim Brown
Solvay Soda Ash Joint Venture
Green River Soda Ash Plant
P. O. Box 1167
Green River, WY 82935

Re: Greenhouse Gas Prevention of Significant Deterioration Draft Permit # PSD-WY-000004-2012.001

Dear Mr. Brown:

The Region 8 office of the U.S. Environmental Protection Agency (EPA) is hereby issuing a final decision regarding the Solvay Soda Ash Joint Venture's Federal Prevention of Significant Deterioration (PSD) permit for Greenhouse Gases (GHG) under the Clean Air Act.

The final permit decision consists of the enclosed final PSD permit and statement of basis. There were no public comments received during the comment period. The final permit decision will be posted on our Region 8 website at: http://www.epa.gov/region8/air/permitting.

In accordance with 40 CFR 124.15(b), the final permit decision is effective immediately upon receipt of this letter as no comments were received.

If you have any questions concerning the enclosed final permit or response to public comments, you may contact Donald Law, of my staff, at (303) 312-7015.

Sincerely,

Debra H. Thomas
Acting Assistant Regional Administrator
Office of Partnerships and Regulatory Assistance

Enclosures (2)

cc: WDEQ-DAQ (w/enclosures)